CROSSBORDER ENERGY

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April 9, 2004

HAND DELIVERED

Legal Document Examiner
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: R. 01-10-024

Legal Document Examiner:

Enclosed for filing in the above-referenced proceeding are the original and five (5) copies of the **Pre-Workshop Comments of the California Wind Energy Association and California Biomass Energy Alliance on Market Price Referents.** Copies have been served on all parties of record in this proceeding.

Please return a filed-stamped copy to us using the enclosed self-addressed and stamped envelope. Thank you for your attention to this matter.

Sincerely,

R. Thomas Beach

On Behalf of the
California Wind Energy Association and
California Biomass Energy Alliance

Enclosures

cc: The Honorable Michael R. Peevey, President
The Honorable Loretta Lynch, Commissioner
The Honorable Susan P. Kennedy, Commissioner
The Honorable Carl W. Wood, Commissioner
The Honorable Geoffrey F. Brown, Commissioner
Presiding Administrative Law Judge Carol A. Brown
All parties on Service List in R. 01-10-024

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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development	)))))	R. 01-10-024

Pre-Workshop Comments of the California Wind Energy Association and California Biomass Energy Alliance on Market Price Referents

The California Wind Energy Association and California Biomass Energy Alliance (CalWEA / CBEA) are pleased to provide these comments in response to the Commission staff's Discussion on Market Price Referents (the "MPR White Paper"), dated March 22, 2004.[1] The MPR benchmark will determine the maximum price that utility ratepayers will pay for new renewable generation under California's Renewable Portfolio Standard (RPS) program. Commission Decision D. 03-06-071 established that the MPR benchmarks will be based on calculations of the all-in costs of a proxy plant – a new gas-fired combined-cycle (CC) for the baseload MPR and a new combustion turbine (CT) for the peaking MPR.[2] The MPR White Paper asks parties to provide comments on how the Commission should determine the specific elements of the MPR benchmarks for the initial RPS solicitation in 2004, including:

[1] *See* "Discussion on Market Price Referents (MPR), MPR Methodologies to Determine the Long-Term Market Price of Electricity For Use in California Renewables Portfolio Standard (RPS) Power Solicitations," prepared by the Energy Division and the Division of Strategic Planning of the California Public Utilities Commission, in collaboration with the Renewable Energy Program of the California Energy Commission, dated March 22, 2004.

[2] *See* D.03-06-071, at p. 19.

- Capital Costs, including land, permit, and generation intertie costs ($ per kW)
- Capital Recovery Factor
- Capacity Factor (%)
- Fixed O&M Costs ($/kW-yr)
- Gas Fuel Costs ($/MMBtu)
- Hedging Costs ($/MMBtu)
- Heat Rate (Btu/kWh)
- Variable O&M Costs ($/kWh), including any necessary pollution offsets
- Any other adders or adjustments to the above components necessary to calculate complete, stand alone MPRs.

MPRs also must be calculated for three different contract terms – 10, 15, and 20 years – for each of the two products — baseload and peaking. Thus, the MPR White Paper asks parties to propose six full sets of MPRs.

CalWEA / CBEA believe that the MPR White Paper provides an excellent starting point for finalizing the needed MPRs. It summarizes the data that needs to be assembled in an accurate, comprehensive fashion. CalWEA / CBEA's comments below build upon the testimony on MPRs that CalWEA submitted in the RPS phase of R. 01-10-024 which culminated in D. 03-06-071. CalWEA / CBEA have updated the information presented in that testimony, to the extent that better information is now available.

Capital Costs. For baseload power, CalWEA / CBEA recommends using values that reflect the cost of recent combined-cycle (CC) projects that have been built or are under construction or active development in California. Such projects include Mountainview, Consumnes, Otay Mesa, Palomar, Sunrise, Elk Hills, High Desert, Metcalf, Pastoria, Blythe, and Contra Costa. In December 2003 Southern California Edison (Edison) provided capital cost and O&M estimates for these plants as part of a "benchmarking" study included in its FERC application for approval of Edison's cost-based contract to purchase the output of the

Mountainview project.[3] In that study, Edison's expert concludes that the Mountainview project will cost $571 per kW, 8% lower than a benchmark of $617 per kW based on the average capital cost of the eleven plants listed above. CalWEA / CBEA believe that these capital costs include land, permits, and generation intertie costs. CalWEA / CBEA recommend that the baseload MPR use Edison's benchmark capital cost of $617 per kW-year. This is an "overnight" capital cost that excludes construction financing (AFUDC) and contingency costs, which need to be added. The Mountainview application also provides estimates for AFUDC and contingency costs for that project.

The California Energy Commission's (CEC) staff produced a June 2003 report that compares the costs of central station generation technologies in California. This CEC study cites $475 per kW as the capital cost for a combustion turbine peaking plant, including land and AFUDC.[4] CalWEA / CBEA have used this CT capital cost.

Capacity Recovery Factor. Edison's Mountainview testimony before the FERC calculates the annual revenue requirement to recover the capital investment in Mountainview, assuming a 30-year life for the project.[5] Edison assumes that the project earns a return on its undepreciated book value (rate base) equal to the utility's authorized rate of return of 9.75%. This use of a regulated utility return is a conservative assumption. Unregulated merchant plants typically require higher returns because they lack the assured market of a regulated utility. However, the electric industry is returning to a model in which most new power plant development either is supported by long-term power purchase commitments or is utility-owned. Given today's environment in the power industry, CalWEA / CBEA can support the use of

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[3] *See* Attachment F, the Testimony of Joseph P. Wharton, to Edison's December 19, 2003 Mountainview Application (FERC Docket ER04-316). This document is available on the FERC's website, at http://ferris.ferc.gov/idmws/nvcommon/NVViewer.asp?Doc=10021543:0 .

[4] "Comparative Cost of California Central Station Electricity Generation Technologies" (CEC Staff Report, June 5, 2003); hereafter, "the CEC Generation Cost Report;" at Table D-10.

[5] *See* Exhibit 1 of Attachment C, the Testimony of Gerard P. Loughman, to Edison's December 19, 2003 Mountainview Application (FERC Docket ER04-316).

Edison's authorized cost of capital.[6] To calculate a levelized capital recovery rate for the baseload MPR, CalWEA / CBEA first increase the annual Mountainview revenue requirement for capital recovery by 8% to reflect the higher benchmark capital cost. We then levelized this declining series of annual revenue requirements over 10-, 15-, and 20-year periods beginning in 2004, using a discount rate of 9.75%. This yields the following levelized annual capital recovery factors: 10 years – 15.10%; 15 years – 14.37%; and 20 years – 13.74%. Finally, we divide the levelized annual revenue requirement for each contract term by Mountainview's expected annual generation to yield capital recovery rates in dollars per Mwh, as shown in **Table 1**:

Table 1 – *Levelized Annual Capital Recovery Cost for Baseload Combined Cycle*

	10-year	15-year	20-year
$/MWh	16.68	15.87	15.18

CalWEA / CBEA recommend the use of the same levelized annual capital recovery factors to calculate the annual capital recovery cost for the combustion turbine benchmark, again for the three contract terms. This yields the capital recovery costs shown in **Table 2** for the CT peaking product.

Table 2 – *Levelized Annual Capital Recovery Cost for Combustion Turbine Peaker*

	10-year	15-year	20-year
$/MWh	84.23	80.15	76.67

Capacity Factor. Edison's FERC Mountainview Application indicates that, although Mountainview will achieve high availability (97% in the summer capacity months, [June to October] and a 92% capacity factor during the other [winter] months), the plant's actual capacity

[6] The illustrative capital recovery factor presented in the MPR White Paper is much too low. It assumes that a new combined cycle plant can be financed with 100% debt, using a 20-year loan at an interest cost of 7.5%. Although this type of financing might be available to a homeowner, it is not available to the developers of power plants. The MPR White Paper's capital recovery factor also does not consider income and other taxes.

factor based on plant output will be 69%, with annual generation of 6,366 GWh. This reflects the fact that Mountainview will be dispatchable, and will not run at full load in all hours when the plant is available to operate.

The CEC Generation Cost Report, at Table D-6, assumes a 9% capacity factor for a CT peaker.

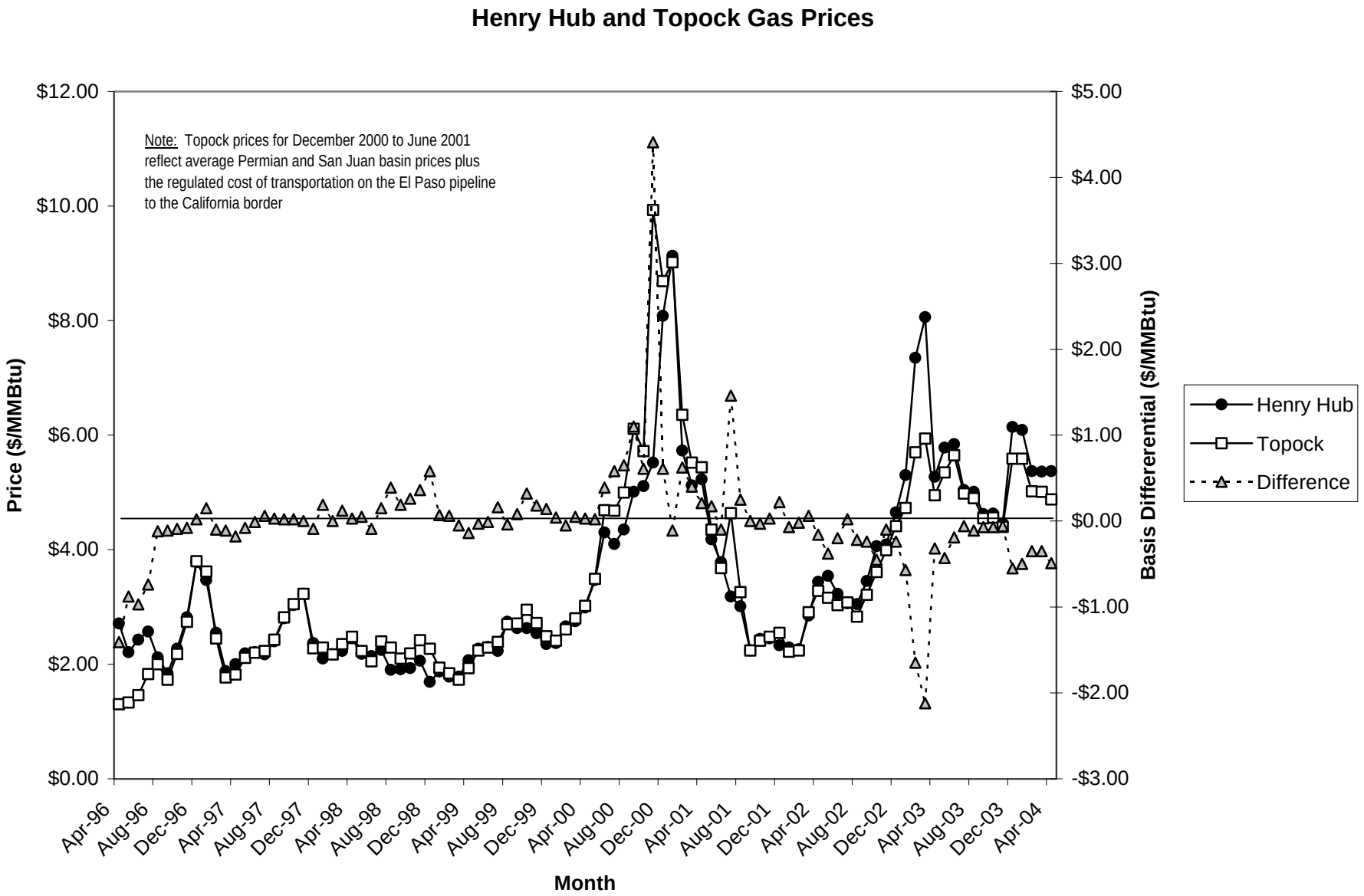
Fixed O&M. Edison's benchmarking study for Mountainview finds that fixed O&M costs for new combined-cycle plants in California average $18.09 per kW-year. We have used this value in our 2004 baseload MPR estimate. Over assumed annual generation of 6,387 GWh per year, these fixed O&M charges amount to $2.97 per MWh.

The CEC Generation Cost Report, at Table D-9, estimates fixed O&M costs for new combustion turbine plant in California average $9.81 per kW-year. Spread over annual generation, these fixed O&M charges amount to $12.44 per MWh.

Natural Gas Fuel Costs. To determine a California border natural gas cost, CalWEA / CBEA agree with the MPR White Paper that a long-term average gas price should be calculated and that the NYMEX / Henry Hub futures market, adjusted for a long-term basis differential, provides a transparent source for such data. Over the long-term, CalWEA / CBEA believes that California border prices tend to equal the Henry Hub, with fluctuations above and below that level as a function of pipeline capacity constraints and expansions. **Figure 1** illustrates these basis swings. Over the past eight years, the basis differential between the Henry Hub and the California border at Topock has averaged essentially zero.[7] For years after the end of the current six years of NYMEX / Henry Hub natural gas futures prices, CalWEA / CBEA recommend escalating prices based on the escalation rates in the California Energy Commission's (CEC) most recent long-term natural gas price forecast for the California market. Based on (1) current

[7] This calculation replaces the very high California border prices experienced during the 2000 - 2001 California energy crisis (December 2000 through June 2001) with average Permian and San Juan basin prices plus the regulated cost of transportation on the El Paso pipeline to the California border.

Figure 1



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Henry Hub futures market prices (as of 4/12/04), (2) a zero basis differential to the California border, and (3) the CEC's assumed escalation in natural gas prices after 2009, the long-term California border gas price for 2004 - 2023 is shown in **Table 3**. The table shows average California border gas prices over 10, 15, and 20-year periods.

Table 3 – *Long-term California Border Natural Gas Price Forecast 2004 - 2023*

Period	**Length**	**$/MMBtu**
2004 - 2013	10 Years	$5.11
2004 - 2018	15 Years	$5.42
2004 - 2023	20 Years	$5.92

Intrastate transportation costs must be added to California border prices to arrive at a delivered cost of gas. Based on SoCalGas' September 3, 2003 BCAP filing of electric generation transportation rates to be effective January 1, 2005,[8] a large electric generator such as Mountainview would pay the following intrastate transportation charges:

[8] It may be argued that SoCalGas' recent BCAP filing proposes new transportation rates for electric generators that are much higher than current (2004) rates and that have yet to receive CPUC approval. However, a significant portion of the increase is the result of lower-than-forecasted throughput and balancing account undercollections. In addition, the filed BCAP rates do not include additional potential rate increases resulting from the pending SoCalGas cost-of-service case (A. 02-12-027) and the Commission's decision in R. 02-06-041 on how to allocate SoCalGas' costs to acquire additional capacity on the El Paso Natural Gas interstate pipeline. Finally, in the BCAP SoCalGas has proposed to set its as-available transportation rates at 130% of the firm rate; PG&E already charges as-available rates that are 120% of firm rates. Thus, these intrastate rates may be conservative to the extent that a power plant must pay as-available rates for the portion of its gas use that fluctuates from day-to-day due to the purchasing utility's dispatch of the plant.

Table 4 – *SoCalGas 2005 Firm Intrastate Transportation Charges for Electric Generators*

SoCalGas Rate Schedule	**Description**	**Rate** *($/Dth)*
GT-F5	Intrastate transportation for large electric generators	$0.50
G-MSUR	Municipal surcharge *(approx. 1.5% of the CA border price)*	$0.09
Total		$0.59

PG&E's intrastate rate for local transmission and distribution service to electric generation is likely to be very close to the SoCalGas transportation rate discussed above. Using the rates proposed in PG&E's pending 2005 rate application, the following rates would apply for firm intrastate transportation on the PG&E system.

Table 5 – *PG&E 2005 Firm Intrastate Transportation Charges for Electric Generators*

PG&E Rate Schedule	**Description**	**Rate** *($/Dth)*
Baja Path - Firm	Intrastate backbone transportation from Topock to the PG&E Citygate	$0.35
Shrinkage	1.2%	$0.07
G-MSUR	Municipal surcharge *(approx. 1.4% of the CA border price)*	$0.08
Local Transmission and Distribution Rate for EG	Transportation to the burnertip from the PG&E Citygate for Electric Gen.	$0.18
Total		$0.68

Thus, the expected PG&E intrastate rate is somewhat higher than the SoCalGas rate. However, California border gas prices for delivery into PG&E's market tend to be lower than border prices for delivery into the SoCalGas system, by up to $0.10 per Dth, thus offsetting the higher PG&E intrastate transportation charges. CalWEA / CBEA conclude that it is reasonable to calculate a single delivered natural gas price for all electric generation within California, based on the southern California border price at Topock plus the SoCalGas intrastate rate. There is no need to calculate separate MPRs for northern and southern California due to gas cost

differences. To be conservative, and because the above intrastate rates represent increases over current rates, CalWEA / CBEA have not escalated these intrastate rates beyond 2005.

Hedging Costs. CalWEA / CBEA continue to support a $0.50 per MMBtu adder for natural gas hedging costs, as several parties proposed in the 2003 RPS case.[9] Other estimates for this value have ranged up to $0.80 per MMBtu.[10] However, if the gas price forecast is based on the NYMEX gas futures market (as CalWEA / CBEA recommend above), then this forecast implicitly includes the cost of hedging, and there is no need to use this adder. Hedging costs should be added, however, if long-term gas prices are based on a forecast of gas market prices that is not linked to actual NYMEX futures market prices.

Heat Rates. For the baseload MPR, CalWEA / CBEA support the use of a heat rate that is 5% over the "new and clean" manufacturer ratings for the CC units that are being installed today. This was the heat rate proposed in the TURN / SDG&E Joint Recommendation in the RPS case. For example, the Mountainview plant uses a full-load, "new and clean" heat rate of 7,000 to 7,100 Btu/kWh.[11] Exhibit 6 of Dr. Wharton's Mountainview testimony shows that Mountainview's heat rate is within the reported range of other new combined cycle plants in California. A 5% margin above this amount to reflect actual operations and ambient temperature conditions results in a heat rate of 7,350 to 7,455 Btu/kWh. CalWEA's RPS testimony recommended the use of a heat rate of 7,400 Btu/kWh heat rate to reflect "real world"

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[9] *See* M. Bollinger, R. Wiser, and W. Golove, "Quantifying the Value that Wind Power Provides As a Hedge Against Volatile Natural Gas Prices" (Lawrence Berkeley Lab, 2002); also, B. Owens, "Power Price Stability: What's It Worth?" (Platts Research & Consulting, March 2003), presented to the March 4, 2003 workshop in the RPS proceeding.

[10] William B. Marcus, "Electric Resources Costs" (February 26, 2003 presentation to the California Energy Commission on behalf of TURN), at 7, citing Southern California Edison's gas hedging costs.

[11] *See* Attachment F, the Testimony of Joseph P. Wharton, to Edison's December 19, 2003 Mountainview Application (FERC Docket ER04-316), at p. 5 of 32. *See* also Reliant Resources' presentation to the California Energy Commission workshop, at the web link: www.energy.ca.gov/2004_policy_update/documents/2004-03-024_workshop/ 2004-03-22_RELIANT_ENERGY.PDF, which cites a heat rate of 7,050 Btu/kWh.

conditions. CalWEA / CBEA continue to support 7,400 Btu/kWh as a reasonable heat rate assumption to use for the MPR baseload benchmark.

CalWEA / CBEA use a heat rate of 10,860 for the combustion turbine, based on data from the CEC's ongoing proceeding on power plant repowering.[12]

Variable O&M. Based on Dr. Wharton's benchmark analysis of O&M costs for similar CCs, CalWEA / CBEA recommends a variable O&M adder of $2.30 per MWh. This number is very close to the variable O&M cost for the Mountainview project. The CT benchmark assumes zero variable O&M costs, consistent with the CEC Generation Cost Report.

Emission Credit Costs. The cost of air emission offsets are low for new combined cycle plants that use selective catalytic reduction technology for emission reduction; nonetheless, they should be included. CalWEA / CBEA have developed an estimate of $0.15 per MWh based on combined-cycle emission data provided in the CEC's ongoing proceeding on power plant repowering (0.05 lbs NOx per MWh),[13] plus recent data on NOx credit costs in the South Coast Air Quality Management District's RECLAIM market ($4 per lb of NOx). Given that NOx offset costs are likely to be the highest in the South Coast air basin, a reasonable statewide value is assumed to be 75% of the South Coast AQMD cost.

The combustion turbine emission costs reflect higher NOx emission rates (0.2 lbs per MWh) for new CTs with selective catalytic reduction.[14]

Line Losses. The proxy plant will also incur line losses in moving power from its busbar to the wholesale market. The CEC's 2003 staff report comparing the costs of central station

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[12] See www.energy.ca.gov/2004_policy_update/documents/2004-03-024_workshop/2004-03-22_RELIANT_ENERGY.PDF.

[13] *Ibid.* These NOx emission rates are also consistent with data in the Otay Mesa Power Plant Application for Certificate (CEC Docket No. 99-AFC-5).

[14] *Ibid.*

generation technologies in California cites average transmission line losses of 5%.[15] Another source of line loss data would be the ISO's system average Generation Meter Multiplier (GMMs). Testimony presented in the CPUC's 2000 proceeding on QF line losses indicated that ISO system average GMMs tend to reflect 2% to 3% losses.[16] CalWEA / CBEA have used an intermediate value of 4% losses for all of the MPRs.

Summary. **Table 6** summarize CalWEA / CBEA's recommended MPRs for both the baseload and peaking products, for 10-, 15-, and 20-year contract terms, based on the assumptions presented above.

Table 6 – *Market Price Referents ($/MWh)*

Product	10-year	15-year	20-year
Baseload	66.94	68.52	71.69
Peaking	165.63	164.95	167.02

CalWEA and CBEA appreciate the Commission's attention to these comments, and look forward to discussing these matters at the upcoming workshop.

[15] "Comparative Cost of California Central Station Electricity Generation Technologies" (CEC Staff Report, February 11, 2003), at Tables C-2 and D-2.

[16] *See* "Prepared Direct Testimony of R. Thomas Beach on Line Loss Issues on behalf of the California Cogeneration Council," filed in R. 99-11-022 on April 28, 2000, at 8.

Respectfully submitted,

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On Behalf of
THE CALIFORNIA WIND ENERGY ASSOCIATION
THE CALIFORNIA BIOMASS ENERGY ALLIANCE

April 9, 2004

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served a copy of the foregoing document, **Pre-Workshop Comments of the California Wind Energy Association and California Biomass Energy Alliance on Market Price Referents,** by Electronic Mail where possible and First-Class Mail where not, on all known parties to R. 01-10-024, named on the service list attached to the original certificate of this document pursuant to the Commission's Rules of Practice and Procedure.

I declare under penalty of perjury that the foregoing is true and correct.

Executed at Berkeley, California, Friday, April 9, 2004.

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Christa Goldblatt